DECLARATION OF RONALD O. NICHOLS REGARDING THE HISTORY OF DWR'S NET SHORT ENERGY PROCUREMENT PROCESS UNDER LONG-TERM CONTRACTS

I, Ronald O. Nichols, declare as follows:

1. I am a Senior Managing Director with Navigant Consulting, Inc. (NCI). The Department of Water Resources (DWR or the Department) retained NCI to provide assistance in establishing and running the State's power purchase program. NCI was also retained by DWR to assist with the bond financing contemplated by the legislation which established DWR's obligation to purchase net short energy and issue revenue bonds to fund such purchases, Assembly Bill 1 of the 2001-2002 First Extraordinary Session (AB1X) and SB 31 of the First Extraordinary Session of 2001-2002 (SB31X). I have personal knowledge of the facts stated herein and if called would testify competently thereto.

2. NCI commenced work for DWR on January 20, 2001 assisting DWR, the Governor's Office and the other agencies involved in the process of making decisions relating to the implementation of DWR's power purchase program, and continues to provide such services. I assisted DWR in its solicitation for long-term power supply proposals and in the evaluations of proposals received. I have also assisted with the calculation of the original revenue requirement, with all revisions to the revenue requirement, and have overseen all NCI work for DWR and the division created to run the power purchase program, the California Energy Resources Scheduling Division (CERS).

3. I have worked as a power resources consultant to the energy industry for more than 22 years. I have specialized in power resources planning, power contracts, power project financing, power project permitting, transmission access and evaluation of power markets. In addition to numerous utility industry assignments nationwide, in 1995, I started work as a consultant for the State of New York when a major utility (Long Island Lighting Co., "LILCO"), was facing insolvency and had the highest retail electric rates in the nation. The New York Legislature passed a bill allowing the Long Island Power Authority to acquire the private utility as a way to reduce and stabilize rates. My team and I provided all of the technical, regulatory and economic analysis associated with the 1998 Long Island Power Authority's $7 billion negotiated acquisition of LILCO and the issuance of $5 billion in financing, the largest transaction of its type at the time. From 1998 through mid-2000, I assisted the Long Island Power Authority in power supply plan evaluation, consideration of alternative power supplies, power supply solicitation, and power contract negotiation.

4. Under my supervision, NCI provides technical support to DWR relating to most aspects of its power purchase program, including, but not limited to:

   (a) Forecasting the electrical needs of the IOUs and the net short requirements of the IOUs customers;

(b) Providing technical support to DWR in negotiating contracts for firm, unit contingent and dispatchable power supplies to meet a portion of the net short;

(c) Developing load and sales forecasts for the revenue requirement;

(d) Developing price forecasting and market simulation tools for the revenue requirement;

(e) Modeling the performance of the DWR power supply contracts as part of the supply to meet the net short requirements of the retail customers of the three California investor-owner utilities; and

(f) Developing a forecasting model for natural gas prices, an important input to estimating power prices and the costs DWR can expect to incur in meeting the net short requirements.

OVERVIEW

5. DWR's responsibilities in supplying power to meet the net short began with the Governor's Emergency Proclamation of January 17, 2001. The powers granted to DWR were later codified in AB1X (Water Code section 80000 et seq.). The department's responsibility for purchasing power was stated in Water Code section 80100, subdivision (a) as:

> "The intent of the program described in this division [Division 27] is to achieve an overall portfolio of contracts for energy resulting in reliable service at the lowest possible price per kilowatthour."

6. At the time that DWR assumed responsibilities under Division 27, nearly all purchases of energy to meet the net short by the investor-owned utilities (IOUs) were from the spot market. Average wholesale energy costs, virtually all of which were in the spot market, had reached 32 cents/kWh in January of 2001. This price was approximately ten times the spot market price of one year earlier. It was generally agreed in the energy sector that reducing reliance on spot markets was important for normalizing the spot market prices that had reached unprecedented levels. That was the approach adopted by the Legislature in AB1X, which, as noted above, directed DWR to use power contracts to achieve a reasonable level of reliability as cost-effectively as possible.

7. The pressures on DWR were considerable. It faced formidable obstacles in avoiding "blackouts" during the coming summer. Energy experts had predicted that California would be plagued with "blackouts" in the summer of 2001 and had predicted prices in excess of 35 cents per kWh during 2001 and prices in excess of 15 to 20 cents per kWh for as long as 2003 and into the summer of 2004.

8. DWR elected to emphasize longer-term contracts as a means to secure new generation capacity for greater reliability and long-term price stability. Market price projections prepared at that time indicated that spot market prices would remain at high levels relative to the prices in the long-term contracts.

9. DWR's energy portfolio strategy also focused on longer-term contracts as the means by which to secure the continuous supplies needed to prevent shortages and to prevent exposure to the price increases that market participants had experienced in the spot market. In compiling a supply base from the proposals received in response to its request for bids, the Department decided to accept contract proposals spanning a ten-year period. DWR sought to tie long term contracts to new plant construction to enhance reliability and control the adverse price implications of short supplies.

10. DWR also sought to include in the longer-term contracts substantial supply for the shorter-term periods during which "black-outs" might otherwise occur and during which prices were expected to be very high. Obtaining that shorter term supply at prices lower than predicted spot market prices put upward pressure on the prices to be paid under the long-term contracts, but these shorter term supplies were sought to accelerate price reduction and stability in the market by reducing the quantity of energy exposed to the spot market.

11. DWR's assembled portfolio of power contracts, as initially executed in 2001, in its peak year of 2004, exceeded 12,000 megawatts. Approximately 5800 megawatts of this capacity is expected to be supplied from new units scheduled to come on-line before 2004. The long- term commitment by DWR to purchase energy pursuant to these contracts enabled the energy companies to justify the capitol investment needed to construct new generation facilities.

12. The Bureau of State Audits in its December, 2001 audit reported that DWR identified the average cost of power produced by the IOUs from their filings with the California Public Utilities Commission (CPUC or the Commission) and its goal in negotiating the long-term contracts was to be no greater than the IOU's weighted average rate of approximately 7 cents per kilowatthour. The Bureau of State Audits reported that DWR achieved an average of 7 cents per kilowatthour in energy purchased under the long-term contracts.

13. Spot market prices for energy at the time that the bulk of the long-term contracts were negotiated were significantly higher than the price of energy established in those contracts. Electricity prices in spot and forward markets fell precipitously in the period following the period that these contracts were signed, confirming DWR's theory of the effect that reliable long term supplies would have on market prices.

DETAILED REVIEW

14. Upon assuming the responsibility for procuring the net short energy requirements of the retail customers of the three investor-owned utilities in California, the Department immediately and consistently sought to procure energy in quantities, types and costs with the goal of regaining reasonable pricing in the market and assuring reliable supply. The Department operated the power supply program with the objective that the quantity and price of power procured by the Department would be just and reasonable, recognizing the extraordinary circumstances present in the market which led to the Department assuming this energy procurement responsibility.

15. Section 80000 of the Water Code, as established by AB 1X provides in part that:

> "The Legislature hereby finds and declares…. (t)he furnishing of reliable reasonably priced electric service is essential for the safety, health, and well-being of the people of California. A number of factors have resulted in a rapid, unforeseen shortage of electric power and energy available in the state and rapid and substantial increases in wholesale energy costs and retail energy rates, with statewide impact, to such a degree that it constitutes an immediate peril to the health, safety, life and property of the inhabitants of the state, and the public interest, welfare, convenience and necessity require the state to participate in markets for the purchase and sale of power and energy."

16. Under this backdrop and with this Legislative imperative, the Department procured the energy and incurred associated administrative and finance-related expenses to carry out the procurement function resulting in the Department's current revenue requirements.

17. The Department used practical criteria in evaluating its energy purchases under AB 1X. Those criteria included, but were not limited to:

    (a) matching an energy supply portfolio to the expected quantity of net short energy requirements,

    (b) seeking a weighted average cost of long-term contract energy expected to be within the combined average cost of energy supply reflected in the IOUs' retail rates, as of January 2001,

    (c) selecting the lesser of comparative cost of proposed energy supplies for similar energy products ,

    (d) providing special consideration to renewable energy supplies, and

(e) setting priority for contracts which support timely completion of new generation capacity to improve California's electric capacity reserves.

18. The "net short" energy requirements are defined as the difference between (a) total energy requirements of the retail end use customers of the IOUs, who were therefore receiving energy from DWR ("the Customers"), and (b) the sum of the energy generated by the electric generating plants retained by the IOUs, the Qualifying Facility ("QF") energy production under contract to the IOUs, and the energy provided under other bilateral contracts between the IOUs and suppliers. Collectively, these last three categories of energy production are referred to as utility retained generation or "URG". All of these factors which influence the net short requirements were considered by the Department in determining the reasonably expected quantity and type of capacity and energy (peak, intermediate, base load and off-peak), which would need to be procured to reliably meet the net short energy needs of the Customers.

19. The Department undertook immediate and repeated efforts to estimate, and periodically refine and verify the net short energy requirements that the Department was responsible for procuring. The initial source of data for the net short energy requirements were obtained in very summary form from the California Independent System Operator (CAISO) staff. Exhibit 1 shows a table of the first information provided to the Department by the CAISO staff to support the Department's initial estimate of the net short requirements. In response to requests from the Department, California Energy Commission (CEC) staff indicated that they did not have any long-term or detailed projections of net short energy requirements on either on a combined basis for the customers of all three IOUs or for the customers of each IOU separately.

20. The CAISO staff had estimates of typical months of load profile for the net short, but the basis of the estimates were unclear, and there was no known explanation of the link between these load shapes of estimated typical daily loads by month and any long-term energy forecast relied upon by the IOUs, the CEC, the CPUC or the CAISO itself. Initially, in late January and early February, 2001, this CAISO input and the forecasts that were part of the NCI load forecasts derived from NCI's version of the Henwood Energy Services Inc. "PROSYM" market clearing price forecast model (which includes specific assumed loads for each of the three IOUs' territories) were used to estimate the net short energy requirements until more definitive information could be obtained from the IOUs themselves.

21. In early February 2001, the Department requested each of the IOUs to provide their latest retail load forecasts and their estimated energy production from their URG, as described in the record. Exhibit 2 shows the requests of February 5, 2001 of Southern California Edison (SCE), Pacific Gas & Electric Co. (PG&E) and San Diego Gas & Electric Co. (SDG&E) for net short forecast information. When this information was supplied by the IOUs, it was used to update and refine the total retail load estimates. As updated and more detailed load data was

obtained, the total load forecast, and the Department's derived estimate of net short energy requirements, were periodically updated to reflect the best available information on the quantity, timing, and type of energy and capacity required to estimate the net short energy requirements of the Customers and the URG available to meet those needs. Specifically, these updated forecasts would modify the peak requirements and the shape of energy requirements during the time of typical days of the week for typical weeks for a month in each year of the approximate 10-year forecast. This total estimated retail load, after being adjusted as described below, was then input to the initial net short energy quantity and cost model applied by the Department. Examples of that model output, and the model itself, in electronic form have been included as a part of the record in DWR's current revenue requirement administrative determination. The periodic updating of the net short forecast was undertaken to ensure that the Department's long-term contract purchase decision making had appropriate objectives as to the amount of supply to be obtained.

22. The net short load forecast model was first developed in early February 2001 and was updated periodically when improved data was obtained from two of the three IOUs in early March 2001. Hourly load data was provided by SCE and SDG&E in response to requests from the Department, but no such detail was initially provided by PG&E. Based upon the information received, as part of a continuing effort by the Department to improve its projection of net short energy requirements, in mid-March, 2001, the modeling of net short energy requirements was upgraded from a typical daily load profile to a typical weekly load profile, by hour. To continue to provide the most reasonably available estimate of the peak and hourly energy needs to assist in its decision making on energy procurement, the net short forecast was also modified periodically as changes occurred in the markets improved information and insight became available to the Department.

23. In early 2001, the load forecasts provided by the IOUs were generally "pre-crisis" forecasts from 2000. These forecasts did not reflect Customer reaction to the crisis situation, or, later in the year, the increase in Customer rates. The Department monitored Customer reaction and associated conservation each month and periodically reflected conservation trends in its forecast of total load.

24. On March 27, 2001, the Commission increased total retail rates by three cents for SCE and PG&E consumers for purposes of recovery of added costs of energy supply. A copy of the order establishing this rate increase is attached as Exhibit 3. Upon the adoption of this retail rate increase, the Department increased the assumed effects of Customer conservation for price elasticity, which reduced the projected net short energy requirements. The model used to estimate the amount of net short energy requirements was modified following the Commission action. Based upon review of the customer reaction to rate increases elsewhere, including increases experienced in the SDG&E service territory in 2000 when its rates increased, a reduction in energy demand equal to 1% for each 10% in rate increase was assumed to be appropriate. For example, an average 30% rate increase would be expected to yield a 3% reduction in average energy

requirements. These adjustments are reflected in summaries of forecasting assumptions and net short energy requirement projections included in the record. The result of this update to reflect the retail rate increase was to reduce the estimated quantity of net short energy requirements compared to forecasts that were used from February through the end of March. Exhibit 4 shows example output of the net short forecast and energy pricing model as of April 18, 2001 and again as of May 11, 2001, in which the estimated effects of conservation on net short energy needs and the estimated effects of changes in total net short prices are reflected in average portfolio energy prices and estimated total cost of energy purchases. The model was updated as contracts were executed or agreements in principle for additional long-term contracts advanced to the stage where it appeared likely that the transactions could move forward to executed contracts, and for various sensitivity cases which were evaluated.

25. In addition to Customer reaction to the crisis situation and retail rate increases, on May 25, 2001, the Governor ordered the implementation of the "20/20" conservation program for the summer of 2001. Under this program, customers would receive a 20 percent reduction in each summer monthly energy costs if the customer reduced energy use for that month by at least 20 percent compared to the same month in 2000. The Executive Order is attached as Exhibit 5. As of summer of 2001, the Department assumed that this summer-only conservation program would be applied in summer 2002 as well as 2001. As of May 2001, the Department and its advisors reasonably projected an approximate 2200 MW reduction in summer peak Customer loads, or about 8% reduction, for the effect of the 20/20 program. Energy reductions for the 20/20 program were included in the total energy conservation estimate, as it is difficult to estimate the individual contribution of each energy conservation program.

26. The above conservation assumptions cumulatively served to significantly reduce the total energy requirements as compared to the forecasts previously provided by the IOUs to the Department in February 2001. These reduced total load forecasts in turn reduced the forecasted net short energy requirements the Department and its advisors used in evaluating the amount and type of contract energy to procure. These reductions in forecast energy requirements were considered by the Department and its advisors to be reasonable estimates based upon the available information on customer reaction to the crisis, price elasticity effects, and the 20/20 program.

27. The level of direct access, whereby electric customers secure power from suppliers other than the IOUs and DWR, has a material effect on the net short energy requirements of Customers. The Department and its advisors made explicit assumptions about the level of direct access in estimating the amount of net short energy it was expected to supply. Exhibit 6 shows historical records of direct access electric loads for the three IOU service territories combined by general class of customer. Exhibit 7 shows this same information expressed as a percentage of total Customer electrical load, and includes the total customer direct access as a percentage of load. Energy provided by direct access suppliers peaked

at a total of nearly 16% of total IOU service area load in May 2000. Direct access loads declined to approximately 7.7% of total retail IOU service area loads by January 2001, when the Department assumed responsibility for net short energy procurement. Direct access as a percentage of total load fell to 4.4% in February and to slightly over 2% by March 2001.

28. In accordance with a provision of AB 1X (Water Code section 80110), the Commission was to suspend direct access. As long as prices for energy in the spot market were high, direct access levels remained low. The Department reasonably projected that direct access would remain at this level, either due to high spot market prices, or because of anticipated action by the Commission to suspend the option of customers who were not already availing themselves of direct access in accordance with the provisions of AB1X. The relationship between direct access and net short energy requirements was an important factor for the Department to consider when determining how much energy to purchase under long-term contracts. The higher the direct access, the lower the net short energy requirements, because the direct access customers "leave the system" and obtain their power supply from sources other than the IOUs and the Department. When the Department was negotiating the majority of its firm energy supply contracts in the first half of 2001, the quantity of net short energy was not projected to be reduced materially by increases in direct access. On June 15, 2001, Administrative Law Judge Barnett of the Commission issued a draft decision in the proceeding on Application 98-07-003 proposing that the Commission suspend the right to contract for direct access effective July 1, 2001. This proposed decision, outlining the reasons for such suspension, is included as Exhibit 8. In developing its portfolio of contracts and mix between long-term and short-term purchases, direct access was assumed to remain at the observed level of 2% of total Customer load until approximately 2006, after which the Department assumed that the markets could have stabilized sufficiently that some level of increased direct access might be reauthorized by the Commission. It was reasonable for the Department to have expected that the level of direct access would not increase beyond those levels experienced in the first half of 2001 until several years later, for the reasons noted above. The suspension of direct access at this level was a material factor in the Department's determination of the reasonable level of energy ever to place under long-term contract.

29. Ultimately, the Commission suspended direct access effective September 20, 2001. By June 2001, spot market energy prices started falling and large electric customers started renewing interest in direct access, and as shown in Exhibit 7, direct access has increased to approximately 14% of total IOU service area retail load as of July, 2002, significantly reducing the net short energy quantities to be served by the Department compared to the objectives of the Department when it entered into long-term contracts between February 2001 and August 2001. This change in direct access has been discussed extensively in the record, and has been the topic of discussion and question and answer in public workshops held by the Commission as well as those held by the Department. The increase in direct access beginning in August, 2001 was a material reason the Department ceased

expressing interest in additional long-term contracts and let several agreements in principle or letters of intent lapse instead of moving forward to complete additional final contracts.

30. Net short energy requirements are directly influenced by the level of utility retained generation, in that net short energy requirements are the difference between total electric loads and the level of energy supplied by the IOUs from the URG. The Department began requesting as much detail as possible regarding URG production beginning in early February 2001. The February 5, 2001 requests shown in Exhibit 2 are examples of such requests. Information regarding generating units owned by the IOUs was reasonably available. Information on existing bilateral contracts between the respective IOUs and other power suppliers was provided sporadically by the IOUs, and in a manner which required repeated adjustments from February 2001 through as recently as July 16, 2002 as data from the IOUs periodically modified. On July 16, 2002, in comments to the Department's proposed revenue requirement determination, SCE provided new information on the level of output under Qualifying Facility ("QF") contracts with SCE which modified the level of estimated energy provided as part of SCE's URG. Similarly, on July 16, in comments to the Department's proposed revenue requirement determination, SDG&E informed the Department of an additional 86 MW bilateral contract not previously disclosed to the Department or its advisors. The Department and its advisors have continually updated the projected quantity of the net short in order to provide not only the basis for projections of the amount of power to purchase, but also to provide the basis for projections of the amount of surplus power to be sold by the Department.

31. Data on Qualifying Facility contract production was particularly challenging to obtain. The CAISO had no solid data on QF production that it could share with the Department. Beginning in February 2001, the Department was particularly concerned about the amount of QF capacity that was off-line. Information regarding the QF performance was somewhat anecdotal and interpretations of the levels of QF production were made by the Department and its advisors based upon partial information available from the IOUs, the CAISO, the CEC, and the Commission. From April 2001 through early June 2001, the Commission staff polled IOU representatives to compile information on QF production to provide information to the Department regarding near-term effects of QF production on net short energy purchase requirements of the Department. Exhibit 9 shows examples of these QF on-line status reports provided by the Commission staff based on this polling of the IOUs. The information assisted the Department in determining the reasonable expectations of quantities of energy the Department would need to procure until QF production returned to more typical historical levels.

32. As of March 2001, the Department estimated that approximately 30% of QF capacity was off-line based upon information obtained from the sources noted above. On March 27, 2001, the Commission ordered the IOUs to resume payments to all QFs, and based upon this order, the Department and its advisors

reasonably projected that QF capacity would come back on line, ramping back up through April, May and June, and then reaching a plateau at 90% of the total level of QF capacity under contract to the IOUs by June 2001. These projections were to estimate the level of net short energy the Department would be responsible for purchasing and were discussed in approximately monthly reports by the Department on its power procurement efforts after March 2001. Page 6 of the May 31, 2001 update report attached in Exhibit 10 shows the actual QF off-line information (QF capacity not operating) as compared to the projections in the Department's forecasts for QF capacity off-line in the net short energy requirements projections. As evidence of the reasonableness of the Department's projections of QF capacity operations, the ramp up between April and July occurred in amounts very close to the Department's projections.

33. As early as January 20, 2001 there were conversations between Ray Hart of the Department and Paul Clanon of the Commission to discuss the Department's plans to pursue long-term contracts. As part of regularly scheduled Governor's Cabinet level calls in which the Commission participated, the Department and its advisors regularly informed all participants in those calls, including the Commission staff, of the status of loads, the status of power purchases, challenges faced in securing contracts, price levels experienced by the Department, difficulties with credit concerns by sellers (both short-term and long-term sales), and related matters. In late January 2001, the Department participated in twice a week conference calls with representatives of several State government agencies, including the Commission, the CEC, the Resources Agency and frequently the Department of Finance and representatives of the Governor's staff to discuss these topics. By early February 2001, the level of concern of reliability of supply, prices of energy, and the status of development of new generation was of such a high level of concern that these semi-weekly calls became daily calls Monday through Friday, every morning. The Department and the Commission had one or more representatives on these coordination and consultation calls daily. In addition to the daily calls, which typically lasted approximately 30 minutes, a Generation Team was established by the Governor's office which met at least weekly, and often twice a week from February 2001 through September 2001. These meetings included the same parties as on the daily conference call, and periodically included other advisors and State agency representatives. The Generation Team meetings, in which the Commission representative participated, would address the status of new generation development, the status of DWR contracting to support new generation development, conservation measures and load curtailment program planning, and many of the same issues discussed on the daily consultation calls described above.

34. The contract and spot market pricing model used by the Department and its advisors from February through early June 2001 was developed as a tool to evaluate multiple combinations of prospective contracts relatively quickly. An example of that model has been provided by the Department in electronic form as part of the record of this determination for those parties who have signed non-disclosure agreements. That model incorporated the above-described net short

energy forecasts. The model also provided for the input of the quantity and cost of energy from executed and prospective contracts, and would project the remaining amount of energy which would need to be provided by either spot market purchases, additional long-term contracts, load management measures, or combinations thereof. Spot market pricing in this model was based on the cost of proxies for power supplies for base load (24 hours a day 7 days a week, or " 7 X 24") power supplies, peak load (16 hours per day, 6 days per week, or "6 x 16") power supplies, and so-called "super peak" power supplies for meeting the top peak needs which occur during less than the full 16 hour peak period. Price proxies were created for each of these periods based upon the estimated typical cost to produce energy from the types of power supplies available in California to meet these energy product needs, considering ranges of gas fuel prices. In addition, market adjustments to the estimated cost of production were added to reflect the dysfunctional market. The annual summary output included as Exhibit 4 is an example of the output provided by this model. The model also provided monthly projections, estimates of the quantity and cost of energy under long-term contracts and the spot (short-term) market quantities and purchases, an example of which is shown in Table 3 of Exhibit 35. This model was used by the Department's advisors to evaluate the effects of contracts during the period when multiple contracts were simultaneously under negotiation. The model enabled substantially faster analysis of the effects of changes in contract supply alternatives than could be achieved with more detailed and cumbersome dispatch models (which can take a day or more to evaluate the effects of a small number of alternative combinations of power supplies).

35. Beginning in April 2001, a more comprehensive and detailed model, using the PROSYM software, was initiated on behalf of the Department as part of the efforts to develop a more detailed planning forecast and pro forma financial operating results for the Department's contemplated bond financing. This model, while more detailed, is an iterative hourly operations model that is far more cumbersome, and was not as well suited to the need to evaluate contract proposals within a matter of a few hours, as was the initial, more approximate model described above.

36. By June 2001, when the PROSYM model was updated for use in the Department's bond financing analysis, the level of daily evaluation of contract alternatives and negotiations had declined to the point where PROSYM results could be used for contract evaluation. By late June 2001, the PROSYM model, reflecting the contracts which the Department had executed and those which were still under active consideration, was the sole tool being used to estimate the market clearing price of energy in the short-term market and to calculate the amount of net short energy to be met by long-term contracts and that remaining to be purchased by CERS' trading desk in short-term purchases. The version of PROSYM which was used for the current revenue requirement determination has been submitted as part of this record of this determination for those eligible parties who have signed non-disclosure agreements.

37. The Department's net short estimate required a detailed set of assumptions and analyses regarding total energy demands of customers in the IOU service areas, the effects of energy conservation, the amount of direct access by such customers, the performance of the IOUs' owned generation, the performance of QF contract suppliers, and the status of the IOUs' other bilateral contracts. This net short calculation was updated as conditions changed and as more information became available. The net short energy requirements, as they changed over time from when the Department first compiled estimates in early February 2001 are documented in the record. The estimates were periodically released in summary form to the public in status reports of the Department's contracting efforts. Exhibit 10 provides monthly update reports prepared by the Department regarding its power purchase contract program for March, April and May 2001. These reports demonstrate the efforts by the Department to track the results of its completed and pending long-term contracts, including comparisons to the projected net short energy needs and the average cost of power under the contracts. These reports were released publicly and maintained on the Department's web site. This tracking is further evidence of the Department's efforts to obtain an appropriate amount of energy to meet the net short requirements.

38. Beginning in mid-January 2001, when the Department was thrust into the position of procuring the net short energy requirements, it faced unprecedented energy price levels, seller uncertainty regarding the Department's creditworthiness, unprecedented levels of generation which was not operational, uncertainty regarding the ability of the Department to purchase gas as a means to enter into certain types of power supply contracts, and lack of action by the Federal Energy Regulatory Commission to set meaningful price caps or price level mitigation. The uncertainty of this procurement situation was complicated by uncertainties regarding the amount of energy the Department was required to purchase, as explained above. All of these factors had to be taken into account by the Department when determining whether to contract for power on the terms it faced and the prices offered in long-term and short-term energy transactions.

39. The unprecedented conditions the Department faced greatly affected its options for purchasing power and the decisions in determining the reasonableness of those purchases. As is noted repeatedly in the record of this determination, in the last half of January 2001, approximately one-third of the total energy requirements of the Customers was being met in the short-term spot market, essentially all in day-ahead, hour-ahead, and real-time purchases. There was inadequate in-state operating capacity to provide sufficient capacity reserves. Natural gas prices had increased to unprecedented levels, in part for reasons documented in the record, including the El Paso pipeline explosion in August 2001 that interrupted the supply of gas for injection into storage to meet 2001-2002 winter needs, payment concerns by gas suppliers, and other matters which have been explained in the record. Exhibit 11 shows the large increase in Southern California Border gas prices before the Department started purchasing energy. Gas price levels were at their peak when the Department was placed in the position of entering into long-

term energy supply contracts. Credit concerns further increased prices, as discussed below. The drought in the Pacific Northwest created additional competition for gas and other fossil-fuel supplied generation, placing further upward pressure on prices. In the last half of January 2001, the daily average price for spot-market energy ranged from approximately $300/MWh to $450/MWh, over 10 times the average price only 6 months prior. The average daily prices for spot market energy from January 17, 2001 through January 31, 2001 are shown in Exhibit 12.

40. The California energy market experienced many stage alerts in the first quarter of 2001 due to inadequate capacity being available, as reported in the record. There were several days of forced curtailment of load through the invoking by the CAISO of rolling blackouts as documented in the record. The last rolling blackout was May 8, 2001. Exhibit 13 shows the intensity of stage alerts due to low electric capacity reserves in January through March, with continued, but lesser concerns through May 2001. This level of unreliability was unprecedented, and was a major factor in the Department seeking to enter into long-term contracts to provide stability to the supply of power to enhance reliability. These reliability concerns were major factors considered when evaluating the reasonableness of entering into the long-term contracts between February and July 2001.

41. The amount of capacity available to serve Customer load was reduced because of unprecedented levels of existing generation that was not in production. Whereas typical winter levels of generation off-line had been in the 3000 MW to 5000 MW level, 9,000 to over 14,000 MW of existing capacity was not producing power during the period from November 2000 through May 2001. The amount of generation off-line was reported by the CAISO daily on its web page and this information was regularly reviewed by the Department and its advisors. Exhibit 14, taken from an August 2001 CEC presentation compares the amount of generation off-line January through July 2001 compared to 1999 and 2000. This graph is accompanied by supporting tabular data in Exhibit 14. As shown in Exhibit 14, the amount of generation off-line in this crucial period was 2 to 4 times that of the prior two years for the same period. Some of this generation was off-line for major repairs and replacements. Some was off-line for planned installation of emissions control equipment. Some suppliers indicated that they were off-line due to limited hours of allowed operations due to air pollution control district operating limitations due to emissions. Still other generators were likely off-line for economic reasons. There was substantial suspicion that some generation was off-line as part of efforts by suppliers to create higher prices for the energy that was produced, although the Department had no ability on its own accord to investigate such circumstances. The vulnerability of Customers to such loss of generating capacity was another reason the Department sought to get power supply under contract, with a significant portion of the contracts having obligations to supply specific energy products at fixed prices. This concern also supported the Department's efforts to get contracts that would either encourage, or ensure the completion of, new generating capacity in California.

42. Exhibit 15 shows the amount, expressed in installed MW of new generation that is estimated by the Department's advisors as of July 2002, based upon known development of power plants and projections by the CEC, compared to the amount of generating capacity which is either contractually obligated to be developed by energy suppliers under contract to the Department, or is proposed in support of energy sales to the Department. As shown in Exhibit 15, through the summer of 2002, approximately 80% of the capacity being added in California during this period is under contract to the Department. This is consistent with the Department's objectives of securing the output of new generation to meet the net short energy needs of the Customers.

43. As noted above, in the first 4 months of 2001, approximately one-third of the QF generation was off-line. Several QF suppliers had reported to the Commission and others that they had ceased production due to lack of payment by the IOUs. In some cases the last payments had been received in November 2000. Exhibit 16 provides examples of news articles, typical of this period, noting the QF power suppliers' claimed inability to operate due to lack of payment or to inadequate price levels to support operations (particularly for natural gas based generation). This lack of production from existing power suppliers created increased concerns about the ability to meet Customer requirements and about continued upward pressure on prices due to supply shortages. These considerations reinforced and supported the Department's interest in obtaining power supplies not only for the long term, but also for the near term, including the summer of 2001.

44. In early 2001, both SCE and PG&E were in default in the California PX market, and were either slow to pay, or had totally stopped payment to, QFs. Due to the defaults of PG&E and SCE, the CAISO also was in default and the Department was called upon to provide credit backstopping for the CAISO real-time and "out of market" purchases as well. This credit-backing role of the Department was acknowledged in the February 14, 2001 FERC order, a copy of which is attached as Exhibit 17. Given difficulties experienced by several sellers in the market, some sellers initially were unwilling to sell to the Department in either the short-term market or under long-term contracts.

45. On April 6, 2001, in response to motions filed by generators, FERC clarified its February 14 order obligating the CAISO to provide for third party credit backing for all CAISO market and so-called "out of market" transactions. A copy of that order is attached as Exhibit 18. On April 13, 2001, the CAISO and DWR signed a letter confirming agreement on the release of a market notice from the CAISO confirming the Department's role in providing the credit support contemplated in the April 6 FERC order. A copy of the April 13 letter and draft market notice is attached as Exhibit 19. Subsequently, on May 10, 2001, the CAISO and the Department agreed to a further clarification of the Departments' credit backing as described in a joint letter, a copy of which is attached as Exhibit 20.

46. The concerns about credit were faced daily by the CERS short term trading desk. Sellers sought to have the Department post letters of credit or cash collateral prior

to agreeing to sell. In several cases, the Department was required to provide payment on unusually short payment terms, from 24 to 72 hours as a condition of sellers agreeing to short-term trading desk transactions. Exhibit 21 provides several examples of communications from energy suppliers who expressed concern about the Department's credit, which made short-term and long-term energy purchases from an already tight supply market even more difficult. This situation reinforced the Department's concerns about adequate supplies of energy in the short-term market in the summer of 2001, and it provided greater pressure to enter into long-term contracts with those parties who were willing to accept the Department's credit and willing to supply energy in the near term under those contracts.

47. These credit concerns were a significant factor in negotiation of long-term contracts. The record includes examples of proposals by sellers in which credit concerns were raised. The record also provides several examples of where DWR and the Department of Finance provided explanations of the Department's source of payment for power purchased, the planned bond financing authorized by AB 1X, and related matters to help provide understanding to sellers of the creditworthiness of the Department. Exhibit 22 provides examples of documentation of credit assurances and explanations made on behalf of the Department and the State Treasurer's Office which were released to sellers in the electricity market to explain the credit position of the Department. Despite these efforts, several prospective sellers would not enter into long-term contracts with the Department, citing credit concerns as a major obstacle (examples are shown in Exhibit 21).

48. The Department and its advisors continually evaluated alternative approaches to enhance its actual credit position and/or the perception of the Department's credit by prospective energy suppliers. For example, attached as Exhibit 23 is an analysis by the Department's financial advisor, Montague DeRose & Associates, of the credit problems and the assessment of the potential for development of a commercial bank line of credit to enhance the Department's credit in the energy market. Although the Department did not agree with the prospective sellers' view of the Department's credit risk, as explained in the various letters explaining the strength of the Department's revenue security, sellers had the ability to choose, and some did choose, not to enter into transactions with the Department. This market limitation caused the Department to focus on the proposals by those parties willing to sell to the Department.

49. Spot energy prices and the cost of energy under gas tolling agreements require the Department to estimate gas prices. The historically high prices of gas in early 2001 created an unprecedented challenge in projecting future near-term and intermediate term gas prices for California. The major source of the increase in gas prices in California was "basis" difference – that is, the difference between the cost of gas at Henry Hub, Oklahoma, where gas is priced (or indexed) prior to shipping to points east and west, and the cost of gas delivered to California. Exhibit 24 provides a February 5, 2001 explanation, prepared by the

Department's advisors, of the history and then current price level of the basis difference for delivered gas and the uncertainty of expectations of gas prices in summer 2001 and beyond. Forecasts of gas prices were reviewed and updated on several occasions to develop updated estimates of market electricity prices as part of the Department's efforts to determine the reasonableness of power supply offers. Exhibit 25 is a summary spread sheet of the initial and periodically updated gas price projections used by the Department and its advisors in evaluating power supply options as market conditions changed. Gas price forecasts (a low, medium and high range) over a 10-year period were developed in January, July and September 2001 and March 2002 as changes in gas supply circumstances and forces which influenced gas availability and price in California changed and prices started returning to levels which are now below what would typically be expected, in part due to a milder than normal winter season, allowing more gas to be in storage, and as a result of the effects of the increased level of gas well completions in late 2000 and 2001 fostered by the unprecedented increase in gas prices in late 2000 and the first half of 2001. These gas price forecast updates were undertaken when the there were indications of potential price change trends during a period of major changes in natural gas prices. The updates were part of the efforts of the Department and its advisors to reflect changes in factor which could influence future electrical energy prices.

50. The Department developed objectives for its portfolio of energy supply resources, and those objectives changed as conditions in the market changed, and as the rights and authorities of the Department were clarified. These portfolio objectives were a key consideration when the Department reviewed its energy supply transactions alternatives and made decisions to enter into those transactions which, in light of all of the circumstances facing the Department.

51. The objectives of the Department in its energy purchase transactions can generally be characterized in five different periods: the initial period from January 17 through mid-March 2001, mid-March 2001 through mid-July 2001, late July 2001 through September 2001, and October 2001 through the date of this revenue requirements filing. The factors influencing the Department's decisions in entering into energy purchase transactions during these different periods are important in assessing the reasonableness of the determinations made by the Department to enter into such transactions.

52. The Department and its advisors set out an initial set of objectives of in contracting for energy supply as described in Exhibit 26, developed by a team of Department personnel and its advisors from January 21 through January 29, 2001. Following receipt of the results of the responses to the Department's first solicitation for power supply bids held on January 24, 2001, and as the Department and its advisors undertook the efforts to procure long-term contracts, the objectives were simplified to generally encompass the following:

(a) to enter into contracts in a quantity sufficient to change the market philosophy to reduce prices in the spot market and to enhance power supply reliability;

(b) to encourage the development of new power generation in California in the 2001 to 2004 period as part of the objective of enhancing reliability;

(c) to require each long-term contract to provide for deliveries to begin in calendar year 2001;

(d) the delivery of energy under fixed price conditions at acceptable levels in the summer of 2001, which was considered to be the period of highest exposure to supply shortage and high potential spot market prices; and

(e) to encourage the development of affordable renewable energy supplies .

Exhibit 26 provides an early (January 29, 2001) summary of the elements of the CERS strategy for its energy purchase portfolio design. This initial list of strategy elements was prepared before the Department was initially advised that there were questions as to its legal authority to purchase gas or to enter into financial hedges to limit its risk of energy purchases that did not have firm prices.

53. Consistent with these objectives, the Department sought energy supplies which would meet at least 50% of the estimated summer 2001 on-peak net short energy requirements (between conservation and contracted supplies at firm prices). Approximately 80% to 85% of projected quantities of net short energy requirements were targeted to be met by bilateral contracts, leaving the remainder to short-term purchase. This general guidance was used by the Department's contract negotiating team.

54. In the January through mid-March 2001 period, the average retail generation rate established within the existing IOU retail rates for the customers for the three IOUs combined was approximately \$0.07/kWh or \$70/MWh. The January 19, 2001 Commission Decision 01-01-046, a copy of which is enclosed as Exhibit 27, referred to the 7 cents per kWh available in retail electric rates of Southern California Edison to pay for power. The average rate for the cost of power included in the retail rates of all three IOUs prior to the March 27, 2001 Commission order authorizing a retail rate increase was approximately 7 cents. Page 8 of the Commission's April 3, 2001 Interim Opinion regarding the California Procurement Adjustment, a copy of which is enclosed as Exhibit 28, shows the power supply cost component of each of the IOUs' retail rates prior to the March 27 rate adjustment. The Department concluded that if the long-term average cost of the long-term contracts was within this price range, the contracts would ultimately result in power supply costs that would be supportable by the then existing average generation rate components of the retail rates established by the Commission. This average price was determined to be reasonable and

appropriate, in light of market conditions in California at the time the contracts were entered into.

55. To achieve appropriate levels of contract energy within the previously noted overall long-term average \$70/MWh price target, the Department issued two requests for bids under a competitive proposal process. These requests for bids ("RFBs") expressed the preference for transactions varying from 1 to 3 years, but acknowledged that longer-term transactions would be considered. Exhibit 29 presents the first RFB, issued January 23, 2001 and Exhibit 30 presents the second RFB, February 1, 2001. The Department opened the process to bids exceeding three year terms in hopes it could ensure sufficient quantity of contract energy to gain market stability at prices at or below the long-term average of \$70/MWh, as explained above.

56. With few exceptions, only bids received for transactions of 5 to 10 years' duration had prices, which on balance, reflected long-term average prices consistent with the existing IOU generation rate reflected in then-present rates (average of approximately \$70/MWh or 7 cents/kWh). The Department summarized the bids received. Excluding the small volume of energy bid for the "super peak" period, the total average price over the term of the bids was estimated to be \$69/MWh (\$0.069/kWh) as presented in the summary tables in Exhibit 31 (included previously in supplementary materials provided in this determination).

57. After receiving the bids from the second RFB, the Department ranked the bids, by like product (such as 7 x 24, 6 x 16, and off-peak product bids), and notified the most promising bidders of a desire to meet to better understand the bids and to determine if suitable terms could be met.

58. The contract negotiating teams consulted regularly on the results of meetings with bidders. The results of negotiations were shared among negotiators and with analytical teams set up to evaluate the results of clarifications or modifications of bid terms. Upon review of proposed terms, recommendations were made to the Deputy Director of CERS or to the Director of the Department. The first step in the process was the execution of an agreement in principle covering the key terms of a prospective contract. Prospective transactions which reached the agreement in principle level were then input to the preliminary contract portfolio model to establish a running record of the estimated net short energy requirements met by the potential transaction and to assess the monthly and annual cost in total dollars and the weighted average cost of the preliminary portfolio of contracts, should they ultimately become fully executed contracts. Exhibit 32 provides an example of tracking sheets that were updated several times per week during the height of the contract negotiations. In addition to the tabular summary of contracts and pending bids under consideration, graphs showing the estimated portion of the net short, estimated total energy provided, and cost of contract energy were provided to the negotiating team and the Department to track the results of its contract procurement efforts. These analyses also formed the basis for much of the

periodic summary monthly reports released to the public, examples of which are included as Exhibit 10, described above.

59. Several of the prospective sellers proposed increases in quantities of energy over the term of the agreement as a means to provide lower prices in the early period of the contracts. In other cases, the contracts started with smaller levels of "market-based" supply which were to be supported by new generation that would not be completed until 2002 or later, at which time the energy quantities to be delivered to the Department increased. This trend contributed to the increasing volume of energy estimated to be supplied by the contracts (or agreements in principle) over the 10 year period of projecting energy quantities and costs. To secure energy in the particularly critical 2001 period, the Department was often faced with committing to a greater volume in later years than was being offered for delivery in 2001. This trend was evident in the summary tracking sheet which summarized the quantity of power supplied in each year of the proposed contract, as shown on the example in Exhibit 32

60. Due to the above situation, the Department was regularly faced with the tension between rejecting bids and having too little supply under contract to provide downward pressure on near-term prices, and the potential of having to commit to more energy in later years (typically 2004 to 2006) than it would prefer if market conditions were more favorable to the purchaser. The Department was also mindful that absent some reasonable assurance of payment under a long-term contract rather than have a seller rely upon the spot market, there was risk of whether sufficient new generation capacity would be developed in time to meet future net short energy needs. These trade-offs were regularly considered by the Department as it evaluated each contract. It was for this reason that the Department regularly reviewed the total estimated energy commitment associated with its contracts that were executed, as well as the agreements in principle or letters of intent to assess the effect of the cumulative energy that would be under contract if all of the pending transactions were completed.

61. From early February 2001 and into the summer months, several times a week, and often, daily, alternative combinations of proposed contract terms were combined in portfolios of contracts. This compilation was undertaken to assess the cumulative effect on percent of net short energy under contract and the weighted average cost per MWh to evaluate the influence on portfolio costs as input to the contract negotiation teams.

62. Through mid-March, 2001, the Department sought to complete a meaningful number of transactions to demonstrate to the market the ability to obtain major reductions in prices for power supply, and to demonstrate that the Department was recognized as creditworthy by suppliers in the market. As of mid-March 2001, the Department met this objective by entering into contracts with Calpine, Bonneville Power Administration, El Paso Merchant Energy, Morgan Stanley Capital Group, Dynegy, High Desert Power Partners, Constellation, Williams Energy, and Primary Power.

63. After the above listed contracts were executed, the Department had demonstrated its creditworthiness to a meaningful representation of market participants. In addition, on February 17, 2001, the CAISO had requested that DWR assume responsibility for contracting with developers of new peaking capacity (the Summer Reliability Agreements) which were under contract to the CAISO, but which the CAISO was perceived to be unable to perform under due to its credit situation. Modification of these contracts to have the Department as the purchaser was deemed by the CAISO to be critical to the reliability of power supplies in California in 2001 and 2002. Demonstration of the Department as sufficiently creditworthy for several major market participants to enter into long-term contracts was important to demonstrate to developers of new peaking generation that a creditworthy alternative to the CAISO was available to contract for the capacity standing behind the various Summer Reliability Agreements ("SRAs"). Beginning in late February, the Department began to negotiate with several of the SRA contractors while negotiations continued with parties who had submitted bids that the Department-had determined to be worthy of further discussion.

64. Whereas initially the Department was uncertain of its ability to purchase gas to meet fuel requirements for generating units which support the bids, the Department received an opinion letter from the Attorney General's Office on February 28 regarding the ability of the Department to purchase gas. This is in addition to the letter received on December 4, 2001 conveying a similar message. A copy of these letters are attached as Exhibit 33. Specifically, the opinion letter indicated that the Department had the authority under AB 1X to acquire physical natural gas fuel under "tolling" contracts, leading to the opportunity to add this approach to the Department's contract portfolio. By early March, the Department was in negotiation to convert some of the bids that had not yet been converted into contracts into transactions which provided for a Department option to supply fuel under a "tolling" agreement.

65. Mid-March 2001 started another phase of the Department's procurement process. The inclusion of the CAISO Summer Reliability Agreements and the start of negotiation of tolling agreements in March 2001 brought greater complexity to the contract negotiation and evaluation process for the Department. Beginning in mid-March 2001, CERS established a more formal contracts negotiation committee review and sign off process. In addition, the contracts negotiation committee met every week to review the status of contracts~~,~~ and to make recommendations on agreements in principle, letters of intent and final contracts. This committee review process also included a standard sign off form to summarize proposed agreements and memorialize approvals by contract negotiators, senior advisors, the CERS risk management committee, legal counsel, and the CERS trading desk prior to signature by either the Deputy Director of CERS or the Director of the Department. Exhibit 34 shows a form of the templates used for this purpose.

66. In mid-March 2001, in addition to its role in assisting in energy procurement, NCI was retained to commence the development of the Consultant's Report for the

Department's bond financing. This effort was the beginning of the efforts to also prepare a revenue requirement which would ultimately be adopted by the Department and filed with the Commission. Shortly after NCI was retained, David Swank of NCI and I met with representatives of the Department of Finance and Kim Malcolm and others of the Commission to discuss the "California Procurement Adjustment" (CPA) established by AB 1X as the originally anticipated method for calculating the revenue which would accrue to the Department for its power purchases. In those discussions, the scope of the analyses needed to develop the revenue requirement, the timing of the Department's bond financing, and the concepts for how the CPA would be defined and determined were discussed.

67. In late April 2001, a series of conference calls were held among the Department, Navigant Consulting, the Commission, the Department of Finance, and the Governor's staff to discuss the nature of the revenue requirement filing and the allocation of costs. In these calls, the parties discussed issues such as the Commission's desire for detailed time of day and seasonal cost information, zonal (point of delivery of power) price information, and the allocation of costs among IOU service territories. In these conference calls, the Department and its advisors explained to the Commission representatives that the Department was procuring energy for the combined net short needs of the IOUs' Customers, and not for individual service territories or classes of customers, noting that allocation of costs would be challenging as a result.

68. In the last week of April 2001, Navigant Consulting representatives had several conversations with the Commission staff in preparation of the first revenue requirement filing, which was presented to the Commission staff for review on May 2, 2001.

69. On March 27, 2001, the Commission adopted retail rate increases for PG&E and SCE, resulting in an average of an approximately three cent increase in retail rates. This increase resulted in changes to the Department's estimate of net short energy requirements to reflect the estimated effects of price elasticity on customer demand. The modified projection of net short energy was then used by the Department to evaluate the quantity of energy it should purchase under long-term contract. This rate increase did not result in any change to the Department's contract price objectives.

70. At this point, the Department provided to the public an update of its estimates of net short energy costs. The most detailed information released by the Department regarding its assumed spot market prices for energy to date during this period were provided by NCI and Montague DeRose for the Department and were included in a report prepared by Blackstone Group LP-Saber Partners LLC, titled "Summary Financial Information, Benefit-Cost Analysis of the Memorandum of Understanding with Southern California Edison, released April 30, 2001. This report, in Section B, included quarterly projections of quantities and average prices of contract energy and the combined costs of spot market energy and

funded programs to reduce customer demand. This section of the report is attached as Exhibit 35. Reviewers of this report focused attention on the summer (third quarter) 2001 estimates of spot market prices at an average of $195/MWh as being optimistically low. As late as May 2001, many market participants, including the then Western Systems Coordinating Council, and other consultants to the industry were predicting substantial rolling blackouts in California and spot prices above $300 to $400/MWh for summer 2001. Exhibit 36 provides examples of the high level of concern about adequate supplies to meet the summer 2001 energy needs. These opinions by market participants and other industry experts were frequently found in the general media and industry publications. Exhibit 37 provides representative examples of the reaction indicating that the estimate of $195/MWh as the average spot market price for summer 2001 was optimistic.

71. In May 2001, the Department released reports demonstrating that between energy conservation and Department contracts for the purchase of energy, approximately 50% of the on-peak hours of estimated net short energy was under contract, reducing the quantity of spot market energy purchases to within the Department's targeted goal. These reports further explained the Department's expectation that this reduced quantity of energy subject to spot prices would put downward pressure on spot prices. The May 31, 2001 status report released by the Department attached hereto in Exhibit 10 is one example of this information. In addition, on May 18, 2001, the Department and its advisors briefed staff of the Commission on the status of its energy procurement program and projections for the contract and spot market prices of energy. This presentation is included as Exhibit 38.

72. Short-term energy prices fell significantly in early June 2001 prior to the FERC issuance of its price mitigation order, supporting the Department's expectation of lower prices in summer 2001 based upon the level of energy supply under long-term contract and due to energy conservation and available load control measures.

73. On June 19, 2001, FERC issued its price mitigation order that applied a formulaic cap on market energy prices in California and throughout the western states. A copy of the June 19 order is attached as Exhibit 39.

74. After several weeks of negotiations with prospective lenders, and receipt of a private letter "indicative" investment grade rating from rating agencies, the Department closed on a $4.3 billion interim loan financing June 26, 2001, providing further evidence of the Department's creditworthiness. Substantial volumes of energy under fixed rate contracts, substantial reductions in spot energy prices, greatly reduced natural gas prices and the release of the FERC price mitigation formula order were items which were of particular focus in the Department's discussions with rating agencies and lenders, contributing to the ability to obtain the interim loan. Receipt of these loan proceeds enabled the Department to cease relying upon new advances of funds from the State General Fund as a source of cash to fund the Department's energy purchases. The Department considered the closing of this financing as recognition by the

financial markets of the reasonableness of its efforts to date in procuring net short energy and acceptance of the Department's expectations of receipt of payment for those costs from the IOUs' Customers.

75. By the time the interim loan was closed on June 26, the Department had completed final contracts with the following suppliers: Allegheny, Alliance (SRA conversion), Cal Peak (SRA conversion), Clearwood (geothermal), Coral (partial SRA conversion, plus other products), GWF, Mirant, PacifiCorp Power Marketing, PG&E ET (wind energy), Sempra, Soledad (biomass), Sunrise Power Co. and Wellhead Power (2 of three SRA projects ultimately negotiated with Wellhead).

76. As the Department and its advisors evaluated long-term contract offers, the prices in the spot market and the "futures" market were monitored as sources of indicators of the perception in the market of what costs would be if the Department continued to rely upon the spot market rather than undertaking to secure long-term contracts, as directed by AB 1X. As noted previously, the California energy market was in total disarray, making it difficult to predict what future costs of energy would be in the spot market. Exhibit 40 shows the trend from January of 2000 of the forward contract prices in each of the California-Oregon Border (COB) and Palo Verde (Arizona) NYMEX trading hubs for electrical energy. Along the bottom, or "X" axis of this graph is the date that a transaction price was offered for purchase of energy in the month in 2001 designated by the legend to the right. For example, in January of 2000, the forward price of energy delivered at COB for the month of August 2001 was about \$50/MWh. By April 2001, the price at COB for an August 2001 delivery was about \$530/MWh, or ten times higher. Prices for delivery at Palo Verde, shown on the second graph in Exhibit 40, shows even higher prices, earlier in the year. These graphs of actual forward contracts show that by June 2001, when the larger volume of DWR contracts were in place for the summer, forward prices fell precipitously.

77. Exhibit 41 compares spot prices at COB to 1-month, 9-month, and 18-month future prices (prices for contracts delivered for a period of one month in the future, 9 months, and 18 months, respectively. From the period of February through May 2001, future contracts, if they could be obtained in any volume at all, were at prices in excess of \$200/MWh for 18 month contracts and \$200 to over \$300/MWh for 9 month contracts, and at times future contracts had prices higher than the present spot prices at COB. These prices reinforced the perspective that the Department would need to enter into long-term contracts if prices meaningfully lower than present spot prices were to be achieved to reduce the \$50 million to approximately \$100 million per day net short energy purchases the Department was experiencing.

78. From January through early July 2001, there had been major changes in the California electricity market. As explained above, during this period, the Department's advisors had continually updated the projection of net short energy,

which was influenced significantly by conservation efforts. The portion of those energy requirements expected to be met by long-term contracts and by spot energy purchases was also updated as more contracts were completed and more letters of intent for contracts were signed. In addition, as noted previously, natural gas prices fell significantly. NCI updated the projected prices of spot market energy as these market conditions evolved from totally dysfunctional in January 2001, to a situation where substantial portions of net short energy requirements were expected to be met by either completed contracts, or agreements in principle considered likely to become final contracts. The above changes had a profound effect on the projection of spot market prices. Exhibit 42 presents a graph which shows the evolution of the spot market price projections from the various models described above. The early projections (March 2001) reflect a lack of long-term contracts and unprecedented high natural gas prices, with no certainty of when gas prices would decline, nor if many sellers would enter into long-term contracts. The early projections were based on the expectation that sellers would continue to sell in the short-term market at prices well above the cost of production without any effective FERC or other price caps, and with no assurance that enough long-term contracts could be completed to influence the volume of energy exposed to the spot market. The spot market prices and the futures prices as shown in Exhibits 40 and 41 are testimony to the market perceptions during this period. By May, as conservation increased and some contracts were entered into, the level of prices in peak hours were reduced to reflect trends that the Department's advisors were observing, and the fact that the Department had entered into contracts for a significant amount of energy under fixed prices. With the use of the PROSYM model starting in June 2001, model results showed results similar to that of the most recent simplified model described above, but with potential for more price volatility through 2001, and lower prices in 2002 as more of the net short was met by contract energy with the completion of more contracts.

79. Mid-July represents the start of the third period of the Department's contracting program. As of mid-July 2001, the Department had completed the majority of long-term contracts it has entered into as of the date of this revenue requirements filing.

80. It became clear that short-term energy prices were continuing to stay low and decline further. During this period, the Department limited its long-term contracting efforts to primarily the remaining renewable energy projects that had prices and contract terms acceptable to the Department: Cabazon (wind), Capital Power (biomass), Santa Cruz Landfill (landfill gas) and Whitewater Hill (wind). In addition, the final Wellhead SRA contract, for the Wellhead Fresno project, was completed during this period, along with the two-year Intercom contract.

81. On September 20, 2001, the Commission issued its order suspending further direct access. This action represents the start of the fourth period in the Department's contracting program. By this point, the Department had ended its contracting efforts and elected to have any remaining letters of intent or

agreements in principle that had not progressed to a final contract expire without action to convert to a final contract. Exhibit 43 summarizes the agreements in principle and letters of intent which either the Department let expire, or the parties declined to pursue. The names of the unsuccessful bidders are redacted, since their offers were confidential until accepted by the Department in a final agreement. This list of potential agreements is evidence of the decision by the Department to cease its contracting due to the changed market conditions, as there were nearly 30 additional contracts which were in various stages of consideration as of September 2001.

82. The September 20 direct access suspension order caused the Department to update its net short energy projections. The significant increase in direct access which occurred between July and September resulted in a major decrease in the projected net short energy requirements, as shown for 2002 through 2004 in Exhibit 44.

83. NCI updated the net short projections and the associated revenue requirements in October 2001, with an update to the PROSYM model to reflect the final contracts completed by the Department, the significant reduction in net short energy requirements from the increased direct access, and an update to natural gas price projections. The results of these projections, and the significant change in the California spot market showed a significantly reduced short-term (spot market) clearing price, as shown in the October 2001 projection included on the graph in Exhibit 42.

84. In December 2001, the California State Auditor released the results of an audit of the Department's energy procurement process. An appendix to that audit includes a summary of comments of the Department and the Secretary of Resources which provides explanation of errors that the Department believes were made in the audit, refuting a number of the findings and providing a number of explanations of the criteria and processes used by the Department to evaluate and enter into contracts. The Department generally found that the Audit Report, while mentioning the conditions that the Department faced in the market in the first half of 2001, lacked an understanding of the implications of those market conditions and the manner in which the California energy market affected the ability of the Department to negotiate more favorable contracts.

85. In November 2001, the Department began internal consideration of the ability to undertake renegotiation of some of the long-term contracts in light of changes in the market, changes in the amount of net short energy and other factors. In December, some of the contracting parties were contacted to inform them of the Department and other State agencies' desire to renegotiate the contracts to better reflect appropriate market conditions.

86. In February 2002, the Electricity Oversight Board and the Commission each filed complaints with the FERC pursuant to Section 206 of the Federal Power Act

requesting that the long-term contracts be voidable or abrogated and establish an obligation for refund.

87. FERC complaints alletted that the terms offered by the suppliers under the contracts were unjust and unreasonable due to the market power that suppliers exercised at the time the Department was placed in the position of obtaining contracts to assure reliability and to reduce the cost of energy. The fact that the EOB and the California Commission claim that the terms offered by suppliers were unjust and unreasonable is not inconsistent with the Department's conclusion that entering into the long-term contracts was a just and reasonable action compared to the alternative of continuing to purchase large volumes of energy at prices which were a multiple of the historic costs in the market. The dramatic reduction in the prices in the spot market, and the reduction in total costs, inclusive of the costs of the contracts themselves, as compared to (a) prices that were experienced prior to action by the Department and (b) prices and energy shortages projected by other knowledgeable persons and organizations in the market absent actions by the Department, are evidence that the actions by the Department were appropriate. Therefore, the actions of the Department entering into long-term power contracts resulted in costs that are reasonable in the context of the objectives of AB 1X. To maintain a reliable power supply, achieve lower prices in the market and halt the unsupportable continued drain on the State General Fund, the Department reasonably determined to move expeditiously to convert spot market purchases in an explosive market into longer-term bilateral contracts.

88. The Department has undertaken substantial renegotiation of contracts entered into and by early May 2002, reached agreement with six of the power suppliers for lower costs and more favorable terms. The Department continues negotiations with several other suppliers with objectives of achieving similar improvements to the contracts, in light of the improved market conditions and more balanced positions between buyer and seller as a result of those changed conditions. The results of the renegotiation of these six contracts were summarized in press releases from the Governor's office on April 22 and May 2, 2002. Copies of these press releases, providing substantial description of the modifications and associated benefits obtained are attached as Exhibit 45.

89. By the spring of 2002, the accounting concerns which led to Enron's bankruptcy started a focus on other energy suppliers and traders, including some of those who have long-term contracts with the Department. In part due to worsening credit ratings and the FERC efforts at settlements, some of the parties in contracts with the Department renewed talks with the Department and other State government organizations for renegotiating terms in the May to July 2002 period. The Department continued to actively review the market for energy, assess its needs, and develop proposals to the counterparties to achieve greater flexibility in operations, reduce prices, reduce the volume of energy under obligation for purchase, and to shorten the term of the contracts, among other efforts. These reductions were sought in light of the improved negotiating position of the

Department and the changed market conditions as compared to those faced in early 2001.

90. In early 2001, it was not clear whether the Department had responsibility for CAISO ancillary services or other ISO charge types. Until approximately April 2001, the Department assumed that it was responsible for ancillary service charges only for the net short energy the Department was procuring, and only those costs were included in the overall estimates of revenue requirements.

91. On April 6, 2001**,** the FERC issued an order which implied that the Department was responsible for all of the CAISO's ancillary service costs and the Department interpreted that it was responsible for all other ISO charge types which were attributable to power supply, but not those for which the load serving entity (the IOUs) were responsible, such as the Grid Management Charge. A copy of this FERC order is attached as Exhibit 18.

92. Ancillary service costs and the many other ISO charge types are extremely complex and are not well suited to projection on a charge-type-by-charge type basis. Moreover, these costs, as well as the real-time energy purchases by the ISO are not disclosed to the Department until after the settlement process of at least 47 days and often can be lagged as much as 60 days from the date the costs were incurred.

93. The Department estimates these costs based upon experienced trends and then calculates them as a percentage of total costs for purposes of estimating monthly revenue requirements. This trend analysis and supporting information for the basis of the formula used in projecting ancillary service and other CAISO charge types for which the Department is expected to be responsible, have been provided in the Department's proposed revenue requirement determination for public comment.

92. In 2001, the Department observed substantial over scheduling by some of the IOUs. This over scheduling contributed to the Department having more energy scheduled for delivery than was required when the real-time loads appeared. As a percentage of total loads, off-system sales were typically not more than 5%. However, had the IOUs scheduled their loads more closely to actual levels, the Department could have procured less in the day-ahead market and better matched supply to load. By 2002, there has been less over scheduling problems, but the much higher than planned direct access loads now served by other power suppliers has contributed to higher off-system sales. The Department's off-system sales still are approximately 5% of total load.

93. The higher off-system sales cause the Department to sell energy into a very depressed real-time or intra-day market. With the Department as the predominant purchaser of energy in California, there is a much shallower market for sales than existed during the operation of the California Power Exchange. As a result, when the Department is forced to sell temporary surplus, whether due to over

scheduling by the IOUs, temperature swings, or higher than expected direct access levels, the sales price to the Department is, on average, about one half the projected market clearing price for purchases in that same day. Exhibit 47 compares the market clearing spot market energy purchase price in the Department's projections used in the revenue requirement for this determination to the prices for off-system sales experienced by the Department. The relationship shows the prices received for off-system sales to be well below the projected price for the Department's short-term purchases. As shown in Exhibit 47, in recent months that relationship has been approximately 50%. This observed relationship is the basis for the projection of off-system sales in the revenue requirement projections proposed by the Department.

I declare under penalty of perjury that the forgoing is true and correct. Executed on August 8, 2002 at Sacramento, California.

Ronald O. Nichols